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CRA Charles River Associates

DESC Stakeholder Advisory Group Engagement - Q&A

Stakeholder Process and Schedule

	Question / Comment	Answer
1	Will all the questions be answered on the website, or just the ones not covered live? And when do you estimate those will be available on the website?	All questions received during Stakeholder Sessions will be posted to the website. We intend to answer and post as many questions as possible within one week of the Stakeholder Advisory Group meeting and continue to post answers until all questions have been addressed.
2	Will DESC send out the model requirements matrix included in the Session I Working Group materials? Will there be a follow up meeting to discuss the model selection?	Yes. We will upload the model requirements matrix in an editable format to the “Stakeholder Materials” section of the Stakeholder website on or around 2/24/21. Also, DESC intends to address Stakeholder feedback as well as our own findings regarding the model capabilities during Stakeholder Advisory Group Session II.
3	Will the presentation slides be sent out to Stakeholders after the meeting?	Yes, all material presented at Stakeholder Advisory Group Sessions will be posted to the “Meeting Presentations and Materials” section of the Stakeholder website.
4	Sierra Club requests that the timeline for coal plant retirement studies and energy efficiency programs be included in the next agenda.	The EE programs will continue to be discussed as inputs to the IRP, but the actual design, modification, and planning of DSM programs will continue to be addressed within DESC’s Energy Efficiency Advisory Group. The coal plant retirement analysis will be included as a topic for Session III of DESC IRP Stakeholder Advisory Group meeting.

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Selection of Capacity Expansion Model

	Question / Comment	Answer
1	What feedback is DESC seeking on the model requirements matrix?	DESC is primarily seeking feedback on the evaluation criteria and the models to be evaluated, that is the columns and rows of the matrix. DESC also welcomes Stakeholder input on how the models presented rank against the defined criteria. Please see further details under the "Stakeholder Materials" page of the website.
2	It sounds like Dominion Virginia does not currently use Partial Chronology in PLEXOS (please confirm), do they currently use Fitted or Sample Chronology and how many blocks per month do they use?	DESC intends to use PLEXOS in a chronological configuration, if selected, through the Fitted Chronology methodology. DESC and Dominion VA are currently using between 6-12 blocks per day to solve PLEXOS.
3	In addition to capacity expansion modeling, will production cost modeling be performed to assess the portfolios identified by the capacity expansion model? If so, which production cost model?	DESC and many utilities use PLEXOS for both capabilities. The LT module sets the optimal resource portfolio and then the ST module is used to determine the optimized production costs.
4	What are Energy Exemplar's licensing terms? Are any restrictions on use of the license, is it the same version of PLEXOS that DESC is using, do you still need a license to view the manual?	We will need to discuss this question with Energy Exemplar to get a specific description of the licensing restrictions or lack thereof. Our presumption is that they are offering the same model as is being used by DESC.
5	When does DESC anticipate deploying PLEXOS or another chosen model, the 2023 IRP?	We anticipate PLEXOS to be fully implemented by the 2022 IRP Update as directed in the Commission Order. If another model is selected, PLEXOS may have to be used as an interim solution for the 2022 IRP Update in which case the new model would be adopted for 2023 IRP.
6	Slide 37 of the Session I Advisory Group Presentation states that inputs to PLEXOS can be an equation. Are inputs limited to vectors that change over time or can DSM cost and availability change dynamically based on the model's selection?	The DSM inputs can be set as a constant or input as time series of values in a datafile. DESC will work with ICF to evaluate combinations of DSM measures and estimate the cost of those measures needed to achieve various levels of reductions in load. These load reductions will be modeled as load scenarios or DSM resources in PLEXOS as appropriate.
7	When modeling DSM as resources, can PLEXOS and does DESC plan to use supply curves based on penetration	PLEXOS can model resources based on characteristics like energy and cost, but not specific types of DSM measures. Adding more than a few DSM resource options is likely to increase solver complexity greatly and reduce

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	rates, or does the model have to use a set cost similar to a generation asset?	the ability to find a solution. Much like a turbine or combined cycle, there will be a limited set of DSM resource options and costs that represent entire suites of measures at different penetration levels. Currently, DESC plans to model DSM portfolios with different cost and reduction potentials such as 1%, 1,25%, 1.5%, etc. The model will have DSM candidate resources with progressive cost and energy reductions.
8	Can you review all the models that were considered by DESC for use in the IRP, not just PLEXOS?	DESC and the Stakeholder Advisory Group will be reviewing a wide range of models for potential use in future IRPs. See Slide 42 of the Stakeholder Advisory Materials from Session I for a full list of the models considered. Stakeholders will also have an opportunity to suggest additional models as part of the Session I homework.
9	What are the hardware and software requirements for the version of PLEXOS that intervenors will license?	Energy Exemplar provides the system requirements for PLEXOS on its website here: https://www.plexosproject.com/articulo-download-plexos
10	The Commission's IRP order requires DESC to file contemporaneously with each future IRP, the modeling inputs, outputs, assumptions, and any post-processing spreadsheets, as well as the model manual. How will DESC provide this access to those intervenors who do not want to or cannot devote resources to utilizing a PLEXOS license?	The data will be made available in the same manner to all Stakeholders. Excel spreadsheets will be provided for all input and output data in addition to any native PLEXOS formats. The PLEXOS manual cannot be provided without a license.
11	A few concerns were raised pertaining to the examples provided on how PLEXOS was used in other IRP processes, which are listed below: 1. Exhibit A says that the license may only be used "for the purpose of reviewing or analyzing the electric price or power cost forecasts developed by the Client." That would exclude its use for IRP purposes. 2. Section 8 and the "Base Fees" section of Exhibit A say that no training or support are covered except as specified in Exhibit A. And Exhibit A says a fee of $2500 per day is required. That seems inconsistent with	The DESC team had raised these concerns with Energy Exemplar (EE). 1. Using PLEXOS for the purpose of evaluating the IRP was discussed with EE. EE representatives confirmed that the intervenor license would allow for review of other aspects of the IRP, including portfolio analysis. 2. In discussion with EE, their team explained that the $8,000 account includes the access to the model and all the automated training modules that are on the website. The $2,500 fee is a daily charge for additional live training DESC will absorb the cost of the licensing fees; however, any additional live training fees would be the responsibility of the intervenor.

	the provision of unlimited support and training that was encompassed in the $8000 option discussed during the IRP workshop. 3. The agreement is written as if someone other than DESC is the licensee and therefore, that someone other than DESC is paying the license fees. 4. The agreement would seem to restrict use of the license to an employee of licensee (Exhibit A), which would be problematic. A consultant to an intervenor would not be able to use it. 5. The agreement also prevents more than one employee from using the license. Consumers is providing two-seat Aurora licenses to intervenors, so EE should do the same here or let more than one person access the license, so that we can work as a team to set up runs. 6. The agreement also states, "License granted by this Agreement shall be for the duration of the Proceeding, but in no event longer than twelve months." The current IRP has gone on for longer than twelve months from the date it was filed, this provision would potentially restrict us from using the license during the duration of the proceeding.	3. EE said that they would be able to accommodate an approach under which DESC paid the cost of intervenor licenses. 4. We have discussed with EE that intervenors may be using consultants' help to form their analysis, and EE explained that they would be able to accommodate this need. Both would need to sign the license agreement and confidentiality/non-disclosure. 5. The EE intervenor license includes a single seat, but intervenors could pursue additional licenses or additional live training if they desire. 6. EE responded that they could extend licenses in the event that it was necessary to accommodate an IRP proceeding.
12	Provision of the model manual is not a "nice to have." It is required on page 29 of Order No. 2020-832.	The DESC IRP team agrees that the minimum requirement includes that Stakeholders or other intervenors have access to all the model documentation. With that understanding, the team evaluated access to the manual as part of the Commission scorecard, which was composed of "need-to-have" requirements. The team was not attempting to determine the exact threshold of what qualifies as a manual, whether that would be a collection of files or a standalone document.
13	Slides 39-40 provide an overview of how PLEXOS is used in other IRP processes. Do you have similar information for the other four models?	Our analysis approach focused on assessing the functionality of other options and whether PLEXOS met certain criteria. We did not perform the same review of intervenor use for the other models were assessed.

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14	Typically, I think of "support" as the ability to ask questions of the vendor if we encounter an issue executing runs, e.g. the model isn't interpreting cost inputs in the way you intend. Is that kind of support available through Energy Exemplar for PLEXOS?	Yes. PLEXOS has a support email that is used by DESC to address the types of issues that you describe in a timely manner.

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Load Forecast

	Question / Comment	Answer
1	There is volatility in load year-to-year, and the magnitude of the peak is highly volatile. What method is used to try and assign a capacity value due to volatility in load? Could we get more detail on ELCC methodology?	In DESC's service territory, the greatest firm load potential is in the winter and so this is when we forecast peaks to be highest. Previously in the 2020 IRP, DESC evaluated a number of different peak hours and the respective contribution of resources on the system during those peaks. The Commission rejected this method and mandated the ELCC at 4.25% of nameplate capacity. See Appendix F of the 2020 Modified IRP for descriptions and calculation of the ELCC used.

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DSM Forecast

	Question / Comment	Answer
1	It's my understanding that the prior characterization of energy efficiency savings relied on load shapes for a subset of measures in DESC's energy efficiency portfolio and that at least two of those measures had significant negative savings, meaning that somehow they cause participants consume more energy not less. Is that the same shape that DESC will use to characterize energy efficiency for purposes of its Modified IRP filing?	The EE profile was developed for use in the ICF Planning Model for the development of the DSM Potential Study and 5-year Program plans. Six of the sixteen measures used in the EE profile, specifically heating and cooling measures, did have some negative impacts. The negative savings are asynchronous cycling of the baseline and upgrade system. Meaning, some hours when the baseline system is "off" the upgrade system would be "on" resulting in negative savings. However, overall, these measures do provide energy savings. It should be noted that the original heat gain/heat loss simulation model used in the development of these load shapes were derived from an ICF developed tool, Beacon Residential Energy Modeling, which uses a DOE-2 engine.
2	Can you please provide the DSM program cost effectiveness calculations, including all incentive and non-incentive cost components?	We addressed the incentive and non-incentive components for cost-effectiveness testing. "Incentive costs" include payments DESC makes in the form of rebates and incentives, instant rebated, and direct installation of measures in low-income communities and small businesses. "Non incentive costs" would include utility administration, third party implementation, marketing, and evaluation costs. Incentive costs are payments made to customers or contractors. See Slide 17 of the Stakeholder Advisory Materials from Session I for more information.
3	Through your new building envelope focus, for how many homes per year do you plan to ensure that the home receives attic insulation plus leak sealing in the envelope plus duct sealing? Can you supply that number from your plan please?	During the current program year, PY11, DESC has forecasted that the Home Energy Check-up Tier 2 will provide building envelope incentives for 359 homes and the low income program will provide the direct install of weatherization measures in 100 mobile homes.
4	Can you provide more specifics on how you arrived at such low impacts of NEEP and HVAC improvements in energy efficiency interventions? How can these programs be prioritized?	Thank you for this feedback. We forwarded this question onto the DSM staff where it can be more appropriately be addressed. The DESC IRP team will be using efficiency assumptions developed as part of that process as well as any cases specified by the Commission. The EE programs will continue to be discussed as inputs to the IRP, but the actual design,

		modification, and planning of DSM programs will continue to be addressed within DESC's Energy Efficiency Advisory Group. For your information: During the 2019 DESC DSM Potential Study both existing housing stock and low-income customers were identified as priorities and will continue to be priorities with the new DSM potential study that will get underway this year. As such, the current portfolio includes doubling the participation in the low-income program, the Neighborhood Energy Efficiency Program. In addition, NEEP will again double under the Rapid Assessment recommendations. NEEP is also in process of undergoing an expansion of the installed measures that customers will receive to include a limited number of refrigerator replacements. For the HVAC program, rebates were increased to encourage 15 SEER adoption and the addition of a rebate to incentivize the removal of electric furnaces and the installation of EnergyStar heat pumps.
5	How can DESC realistically reach a 1% energy efficiency target with primarily only energy audits? Energy audits alone cannot achieve energy real efficiency gains without implementation of audit recommendations.	Thank you for this feedback. We forwarded this question onto the DESC DSM department where it can more appropriately be addressed. The DESC IRP team will be using efficiency assumptions developed as part of that process as well as any cases specified by the Commission. The EE programs will continue to be discussed as inputs to the IRP, but the actual design, modification, and planning of DSM programs will continue to be addressed within DESC's Energy Efficiency Advisory Group. DESC has not stated that a 1% energy efficiency target could be achieved only with energy audits. The DESC DSM portfolio of programs consists of 10 programs – 7 residential and 3 C&I. The Home Energy Check-up program, which is a residential audit, is just one of the DSM programs. For eligible customers, Tier 2 of the Home Energy Check-up allows customers to follow through on the recommendations made during the residential audit. Four of the DSM programs include the direct installation of measures: Home Energy Check-up Tier 1 and 2; the Neighborhood Energy Efficiency Program (core program and weatherization measures for mobile homes), the Multifamily Program (residential units and common areas) and the Small Business Energy Solutions Program.

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6	Several DSM measures can provide some of the "reliability" criteria, e.g. Volt-VAR optimization, demand response, etc. are you accounting for the benefits that can be provided by demand-side resources?	DESC models DR as a general program that reduces demand at a certain cost. The reliability benefits of DSM are captured in the reserve margin as DR can meet portions of the reserve margin requirements.

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New Resource Cost and Performance Assumptions

	Question / Comment	Answer
1	For Dispatchability and Operational Flexibility, inverter-based resources can be dispatched downward incredibly quickly and can ramp upwards just as quickly if you hold headroom. Multiple studies have been conducted as well as real-world operations of solar providing Automatic Generation Control. You should consider a class of inverter-based resources that are procured to provide dispatch flexibility rather than just must-take. Inverter-based resources are required to be capable of providing VAR support and have a broader range of reactive power that can be provided compared to fossil. Are you capturing this in your reliability criteria?	DESC is aware of operational projects where solar provides Automatic Generation Control that is beneficial for other utilities. Traditionally, DESC models the resources that have been proposed and offered on the DESC system, and those proposed assets did not include solar providing AGC. DESC recognizes that part of the Stakeholder process is gaining feedback on the type of assets modeled and will consider these suggestions.

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Scenario and Market Assumptions

	Question / Comment	Answer
1	Can DESC elaborate on the definition of "expected conditions?" as described in slide 44 of the Session I Stakeholder Advisory Group presentation?	Expected conditions reflect DESC's most likely view of the future. This view, for example, contemplates the low gas price scenario, energy efficiency reductions of 1% and a $12/ton carbon price. Please see the 2020 Modified IRP, page 75 for additional details.
2	I agree the use of scenarios can be effective to identify risks but depends on if scenarios are crafted as "likely" futures or possible "extreme" futures designed to test potential resource plans. I wouldn't consider a $35 carbon fee as "extreme" since these extreme measures should truly test the system. Additionally, if there is a need to get to 80% clean energy by 2030, it would be helpful to know in advance, under the current situation, how that is possible before any regulation is created.	DESC agrees that it is important to consider history and potential future events that are realistic boundaries when doing scenario testing. To clarify, in all CO_2 pricing scenarios DESC also escalates the carbon fees over time. In the $35/ton scenario, for example, the CO_2 price rises to over $300/ton by 2050. This may or may not constitute an "extreme" scenario but has significant impacts on the system. Thank you for your comment regarding the 2030 target.
3	If approved, might SEEM change DESC's market access assumptions for energy purchases?	SEEM is focused on the inter-hour 15-minute non-firm market. Therefore, it does not contribute to the reserve margin, and will not be used in reserve margin planning. It is more likely to facilitate real-time balancing and renewable integration. Implementation of SEEM could impact the cost effectiveness of different resources if they are able to sell energy into this market at favorable cost.
4	Will you be doing a scenario for the administration's clean energy standard of 80% by 2030 and 100% clean energy by 2035?	DESC has not yet investigated this proposal in detail and will take the suggestion into consideration.
5	Given that there is a proposal to extend the ITC out in time, and expand it to stand-alone storage, have you considered a scenario that models those ITC changes? A few bills proposed stand-alone storage or storage getting the ITC at the same level. Grid charging is no longer a detriment. There's been momentum and a couple of bills. In terms of timing, we may see these get passed at some	The 2021 IRP Update will utilize the same resource plans as the 2020 Modified IRP, with a potential additional low carbon plan. DESC will monitor changes to the federal ITC as appropriate in future IRP updates.

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	point this summer. Timing - could there be an upside that looked at these?	
6	Is there a liquid hub available for significant reliance on market purchases/sales?	DESC does not participate in an organized capacity or energy market, so we limit our reliance on purchases and sales and energy and capacity.

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IRP Resource and Retirement Plans

	Question / Comment	Answer
1	In the Session I Advisory Group Presentation, DESC explains that it has verified the capability to optimally retire units and replace them with efficient mix of resource additions. How was this verified and how were "optimal" retirement and "efficient mix" defined in this process?	Optimal and most efficient mix are based solely on lowest NPV of all utility related costs. Reliability is handled outside the model. DESC has not independently verified the “optimal” results produced by PLEXOS, rather it is relying on the credibility of the model in the public domain at this point in time.
2	Could Stakeholders get written follow-up on the ability to use the DSM cost curve? How are you collaborating on the retirement studies?	The DSM cost curve was not used in the IRP. No collaboration on retirement studies has taken place but this is expected to take place as we move forward with our studies over the next two years.
3	Help me understand how replacement assumptions impacts analysis on the front end? Would it be better to deploy this at this stage?	Due to required process for evaluating transmission impacts, we have to describe exactly what changes to the system we want the transmission group to study. We have added the request letter to the Stakeholder Website for your review.
4	Why is DESC already laying out the retirement order rather than allow the study to determine the order? Part of doing the analysis is to optimize the order. What criteria are you using to determine Wateree, then Williams, and then Cope? For the replacement cases on Slide 63, wouldn't the use of a capacity expansion model provide a more robust set of replacement options for retired units?	DESC decided on the retirement order according to plant characteristics. Cope is ordered last since it is the youngest, newest, most reliable, and has dual fuel capability with gas. Wateree has lowest capacity factor and lowest site cost. Finally, due to its location on the transmission system, outages at Williams result in the most operational difficulty meaning it may be more complicated to replace.
5	Why will this retirement study take years? Last year, Dominion completed a retirement study in Virginia in a few months. Can you give a more specific timeline?	DESC aims to have the Wateree retirement study completed by the end of 2021.
6	The peaking proposal does not appear to be a one-for-one replacement. It proposes an additional 85 MW. Can you explain?	The turbine replacement is a one for one replacement of like kind vital resources at the end of their useful life. The 85 MW being questioned appears to compare winter and summer ratings inappropriately.
7	Why were certain retirements presented here omitted from the IRP?	The retirements were not omitted in the IRP. RP3 considered retirement of Wateree, RP4 evaluated retirement of McMeekin and Urquhart, and retirements of both Wateree and Williams were in RP 8. DESC still needs to

		do a full study of the retirements to understand the full impacts of their retirements.
8	For cost implications, will a securitization option be considered as part of any sensitivity analysis included in these studies?	Securitization requires legislation from the General Assembly, and we don't have it in South Carolina. Without legislation, securitization is not an available option at this time. There is no enabling legislation giving the Commission the authority to approve or order securitization of any retired plants.
9	A one-for-one replacement seems to be built-in assumptions across scenarios. Given that DESC already has excess capacity and Wateree 2 is already offline for a significant period, are you considering scenarios that do not include 1 for 1 replacement of coal plants?	DESC dos not assume a 1-for-1 replacement standard. Rather, resources are added to meet the required reserve margin in MW.
10	About reliability: where does the possibility of planned and unplanned outages fit in?	DESC does build in planned outages to modeling, and updates forced outage rates while considering generation units. If a unit has a high forced outage rate, this value will count against the generating unit.
11	Why is the timeline for the coal plant retirement studies so unnecessarily and unjustifiably long?	The timeline for a comprehensive coal retirement study ("Retirement Study") is neither unnecessarily nor unjustifiably long. A Retirement Study involves the coordinated efforts of multiple Dominion Energy functions. DESC Resource Planning will lead the overall effort and perform resource adequacy, reserve margin calculations, reliability, and system cost/resource optimization studies. To meet the pace of implementation required by SC PSC Order No. 2020-832, DESC Transmission will now perform a transmission impact analysis ("TIA") for the coincident retirements of both the Wateree Station and the A.M. Williams Station. The TIA will show if the electrical impacts of the retirements are technically achievable and identify transmission cost estimates at the retirement site as well as upgrades at the replacement capacity study sites. DESC Power Generation will plan for the community impact including employee relations and will develop plans and costs for demolition, site restoration and any site re-use, and develop plans and costs for DE-owned replacement projects. The DE Environmental Department will study and report on environmental impact/benefits, areas

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		of continuing compliance, and closure costs with special attention toward ash ponds and ash landfills. Performing the TIA has been identified as the longest lead time item and is required to inform other activities mentioned above for the timely and successful completion of the Retirement Study.

12	How will your long, two-year schedule for coal retirement studies align with your decision due by October 2021 to select an ELG compliance pathway for each coal plant? How will you avoid committing DESC and its shareholders and ratepayers to unnecessary ELG upgrade costs?	With respect to the October 2021 ELG "decision" referenced in the question – this is a deadline for the Company to make a regulatory ***filing*** with SC DHEC regarding its compliance plans with the ELG rule, not an actual expenditure.
		
		▪ For Wateree, the Company plans to file for bottom ash compliance by 12/31/2024 and to opt for the Voluntary Incentive Program ("VIP") route for Flue Gas Desulfurization ("FGD") wastewater, which results in an automatic compliance deadline of 12/31/2028 for that waste stream. The ELG rule allows for, and the Wateree permit will include, an "auto-transfer" option to move from the VIP route to retirement, if the Company determines it is prudent to retire the Wateree units prior to 12/31/2028.
		
		▪ For Williams, the Company plans to file for a bottom ash compliance deadline of 12/31/2025 (as significant equipment modifications are required to comply with this aspect of the rule).
		
		    ▪ For FGD wastewater, if the Company opts to take the VIP route, this will result in an automatic compliance deadline of 12/31/2028 for that waste stream. This will also allow for the inclusion of an "auto-transfer" option to move from the VIP route to retirement, if the Company determines it is prudent to retire Williams Station prior to 12/31/2028.
		
		    ▪ If the Company opts for the Best Available Technology ("BAT") route for compliance with the FGD aspect of the rule (following planned piloting studies later this year), the Company will request a compliance deadline of 12/31/2025. To retire the facility or swap

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		to the VIP technology pathway (prior to 12/31/2025) would require a permit modification, which the Agency is empowered to allow under the ELG rule. ▪ The Company is actively working on piloting and engineering studies to determine the best and most cost-effective potential ELG compliance pathway for Williams ahead of the October 2021 SC DHEC filing. The Company is actively undertaking the coal retirement studies prior to committing to the substantial ELG compliance project costs while also continuing with engineering and pilot study activities such that it can quickly move into compliance project implementation, if required for continued system reliability.

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Risk Metrics and Analysis

	Question / Comment	Answer
1	Can DESC elaborate on the updated quantitative risk analysis and how it is applied to the company's preferred plan?	Please see the 2020 Modified IRP for further details. This should be publicly available prior to the next Stakeholder Advisory Group Meeting.
2	On slide 44 of the Session I Stakeholder Advisory Group presentation, why is levelized cost a metric instead of net present value? Can you define all of the metrics on this slide, e.g. reliability?	This is an error on the slide, levelized cost should be replaced with levelized net present value. DESC defines the metrics on slide 44 of the Session I presentation as follows: ▪ Levelized Net Present Value: The Levelized Net Present Value metric is a comprehensive measure of the relative costs to customers of each of the fourteen resource plans over the 40-year period from 2020-2059. The comparison is based on the forty year levelized net present value of the incremental costs of each resource plan. The incremental costs include incremental operating costs, capital costs for new generation, incremental capital costs for ongoing operation and maintenance, and DSM costs. ▪ CO2 Emissions: The CO2 Emissions metric compares the expected emissions from the fourteen resource plan as forecasted at the end of 40-year period ending in 2049. ▪ Clean Energy: The Clean Energy metric compares the fourteen resources plans based on how much energy they produced as forecasted at the end of 40-year period ending in 2049. ▪ Fuel Cost Resiliency: The Levelized NPV Fuel Cost of generation plans as modeled in the Modified 2020 IRP fully captures fuel costs and anticipated changes in fuel costs over a 40-year planning horizon for each plan. As a result, the Levelized NPV Fuel Cost metric provides important data about how plans perform in the face of fuel price changes. ▪ Generation Diversity: Each of the resource plans modeled assumes the addition or retirement of different suites of generation sources. For that

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		reason, each of the plans results in a different level of generation diversity at the close of the 40-year planning period. The generation diversity of each resource plan is ranked according to the percentage that the generation mix it creates is concentrated in any one type of generation asset. ▪ Reliability Factors: DESC has identified a set of reliability factors that measure the generation types' ability to supply certain ancillary services, operating characteristics, and capabilities and meet certain locational considerations that support grid requirements in normal operations and in restoring power after storms or outages. ▪ Mini-Max Regrets: The Mini-Max Regret analysis evaluates each resource plan against the lowest cost plan in each scenario and calculates the difference in the 40-year levelized NPV between the plans. The maximum change from the best plan in each scenario sets the max regret score for each resource plan. ▪ Cost Range Analysis: The Cost Range Analysis evaluates the variation in the 40-year levelized NPV for each plan across the 27 scenarios that were modeled. The maximum variation for each plan sets the score.
3	Although I don't have a strong opinion on which risk metric approach is preferable, I do feel strongly that stochastic analysis is often not the best way to capture risk. I prefer a scenario analysis with a range of scenario-based outcomes. I'm not a fan of the technology risk metric. This metric comes from the need to be concerned with fuel risk, but as we move away from that, it's less necessary. I believe the diversity of resources is a better metric.	The DESC IRP team agrees that stochastic analysis has to be properly implemented to be significant. We also agree that risk associated with some technologies are fuel related, which is a factor often considered in stochastic analysis, but some related to technology risk are often not considered. DESC's IRP analysis uses scenarios, consistent with this observation, to consider a wide range of factors
4	Doesn't reliance on purchases also reduce the risk of being reliant on stranded assets?	We recognize that there are potential risks and benefits of reliance on purchased power. With a greater reliance on the market comes less reliance on owned assets. Therefore, if DESC owns assets that operate

		below the cost of the market there can be advantages. On the other hand, if DESC owns assets that are above the costs of the market, this can strand assets.
5	Is commodity price risk specific to fuel costs only or are you considering broader commodity risk (steel as an example)?	The Commodity price risk metric is used to evaluate the cost risk associated with fuels burned; it does not include steel. DESC assumes new generator costs, including steel prices, rise based on a Handy-Whitman index when evaluating portfolios in the IRP.
6	Given recent events in Texas, are potential fuel supply interruptions part of the reliability analysis?	Yes. Our natural gas units rely on multiple pipelines from shale gas sources from the Gulf coast and several have oil fuel backup. Additionally, coal maintains a 60 to 90-day fuel supply.
7	Are you using 2049 as a 1-year snapshot on carbon emissions? Because cumulative emissions throughout the period will cause cost risks to ratepayers if CO2 is regulated	The impact of cumulative emissions are captured in the CO_2 costs incurred by each different portfolio. DESC will consider reporting a cumulative CO_2 table into the outputs.
8	Is the CO2 metric cumulative over the entire planning period or just in the year of 2049?	The CO2 emissions metric measures the portfolio's 2049 emissions as a measure of progress towards DESC's 2050 target.
9	Have you considered tracking water intensity as a core metric?	DESC does not consider the water intensity of the portfolio as a core metric but will take that suggestion into consideration.

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Miscellaneous / Other

	Question / Comment	Answer
1	At any point during the stakeholder process will DESC make its modeling files available to stakeholders who have signed the NDA?	Yes, DESC will make the modeling files available that are used to support future IRP filings at the time those future IRPs are filed.
2	Will DESC also be using Strategist's Differential Cost Effectiveness module? If so, how will it provide Strategist licenses to intervenors?	Strategist is an ABB software. DESC does not currently have licenses to use Strategist and will not be using Strategist's Differential Cost Effectiveness module in its future modeling.
3	Please provide the license agreement that Energy Exemplar will require intervenor licensees to sign.	Energy Exemplar requires that stakeholders that wish to view the utility's model within PLEXOS sign a limited license. Please contact Energy Exemplar at: dana.harris@energyexemplar.com for a copy of the limited license.
4	The Commission's IRP order requires DESC to absorb the cost of intervenor license fees, does DESC plan to do so?	Whatever cost DESC incurs to comply with the Commission’s order will be charged to the Company’s customers.
5	Does DESC consider 2022 to be a full IRP update year? Rather than an annual update?	DESC understands that 2022 will be an update year and that the next full IRP will be in 2023.
6	The footnote on slide 35 says that companion financial models are used for revenue requirement modeling. Has Dominion chosen a specific financial model?	PLEXOS has a financial model in their LT plan which models revenue requirements. It also has financial models. In the past, DESC created spreadsheet models to create total cost models outside of the modeling software, but this will be less necessary while using PLEXOS. There will still be some aspects that DESC will have to model in external spreadsheets to accurately reflect the way that the Commission requires revenue requirement reporting.
7	SWEPCO created a Stakeholder working group that can develop and create a limited number of sensitivities or cases. Then, the utility ran it on their behalf. Would DESC be willing to do that?	The team’s first aim is to reach a consensus on the model that will be used. We intend to be responsive to Stakeholder feedback but how the model will be used is a discussion for future Stakeholder meetings.
8	I am unaware of any other markets that measure inertia, and there is no need for this metric. As electric utility technology develops, there will be no need for this metric.	DESC chose to include inertia in the study since the factor is still relevant to the reliable operation of the current generating system. DESC will continue to evaluate the factors and contributions to those factors by each resource type.